Amy G. Rabinowitz
Assistant General Counsel

October 11, 2005

Mary Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Dear Secretary Cottrell:

On behalf of Massachusetts Electric Company and Nantucket Electric Company, I am enclosing our responses to the Department's sixth set of information requests.

Thank you very much for your time and attention to this matter.

Very truly yours,

Amy G Rabinowitz
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DTE-LDC 6-1

Request:

As an alternative to mandatory inspection and maintenance guidelines, please identify new Service Quality performance measures to realize the effective maintenance of your system?

Response:

The realization of "effective maintenance" of the distribution system is reflected in the reliability results that are achieved. For example, inadequate tree trimming will manifest itself in the number of tree-caused outages increasing, or in the magnitude of the tree-caused outages increasing. All other possible metrics either deal with inputs to the process or relate very superficially to the output of the maintenance, and none will provide any real indication of the effectiveness of the maintenance effort.

By their very nature, highly prescriptive mandates for inspection and maintenance of distribution systems inevitably do not reflect the unique aspects of each company's circumstances. For example, the optimal tree trimming cycle for a more urban company would likely differ from that of a rural utility. Mandated inspection and maintenance targets would also restrict management's ability to adjust activity to meet the dynamic needs and priorities of the business. For these reasons, it would not be advisable to institute a set of "one-size-fits-all" specific Service Quality performance measures aimed at system maintenance.

Alternatively, the Department could order each distribution company to submit its own comprehensive plan for the effective maintenance of its system. This could be a multiyear plan and include prioritized maintenance activities, along with specific targets. Each company could then prepare and submit an annual review of the past year's performance, along with updated targets for the coming year(s). In this manner, each company could tailor its own plans to reflect its own individual circumstances and explain actual variances from its plans, and the Department could have an effective tool to review each company's maintenance activities.

Prepared by or under the supervision of: James D. Bouford

DTE-LDC 6-2

Request:

Using the Company's available historical outage information, please provide, in an active excel spreadsheet, a calculated required minimum number of customers affected to qualify for exclusion under IEEE-1366, and the associated values of α (Alpha), β (Beta), T_{MED}, SAIDI, and total customer minute interruption for the years 2000, 2001, 2002, 2003, and 2004, for each of the following assumed interruption durations: 1 minute, 5 minutes, 60 minutes, 360 minutes, 720 minutes, 1,440 minutes and 2,880 minutes.

Response:

The IEEE 1366-2003 standard does not exclude reliability events. Instead, the process within the standard segments the data into major event days and routine days. Major event days are days upon which either system design and/or operational limits are exceeded. Identifying these days separately from the routine performance days provides for better decision-making opportunities based upon a company's routine performance. The reliability events on non-major event days are utilized to calculate the system metrics. The Company assumes that the request is basing the required calculations on the interruption events occurring on non-major event days.

Please refer to the attachment to this response and the Excel file named "DTE Set 6 Att.xls". The attached spreadsheet provides information that the Company believes the Department is requesting. The Company's interpretation of the question is that the Department would like the Company to use its historical data to calculate T_{MED} using the definitions provided within the IEEE 1366-2003 standard; then for the durations provided, calculate the corresponding level of customers affected that would be required to exceed the T_{MED}. The attached spreadsheet provides this result. It is important to note that the T_{MED} would never be exceeded for an event that lasted 1 minute, as this would require the interruption of between 3.5 and 4.5 times the number of customers in the Mass. Electric service territory.

The "2.5 β methodology" used to calculate T_{MED} provided in the IEEE 1366-2003 standard is not based on customers affected, but instead is based upon the SAIDI accrued each day during the year. There is no relationship between the number of customers affected by an event and a major event day identified by exceeding the T_{MED}. Those events that are identified by the percentage of affected customers served by a company may not identify those events that have truly exceeded the design and/or operational capabilities of a company, whereas those events occurring on a day where the SAIDI exceeds the T_{MED} value are assured to have exceeded either the operational or design limits of the company.

DTE-LDC 6-2 (continued)

The Working Group on Reliability, formerly known as the Working Group on System Design, explored many approaches to defining major event days before SAIDI was selected as the best indicator of these days. The Working Group on Reliability began by considering customers interrupted as a potential metric for identifying major event days. Using the number of customers interrupted has a tendency to overemphasize events that are substation-based as major event days, especially for small companies. The point of identifying major event days is to identify days on which the utility has truly gone into a different operating mode; days upon which a company's routine capabilities have been exceeded. Identifying such days and segmenting them from the remainder of the days allows both regulators and utility personnel to evaluate the true underlying performance of a utility. It also allows the parties to evaluate performance during major event days because these days have been segmented for separate evaluation instead of being excluded entirely from the data being evaluated.

Prepared by or under the supervision of: Cheryl A. Warren

Massachusetts Electric Company
Nantucket Electric Company
Docket No. D.T.E. 04-116
Attachment to DTE-LDC 6-2

IEEE-1366 Calculations

Mass. Electric	2000	2001	2002	2003	2004
SAIDI IEEE	82.30	95.73	117.44	100.08	122.31
alpha	-2.34	-2.31	-2.25	-2.13	-2.05
beta	1.44	1.42	1.42	1.43	1.42
Tmed	3.50	3.48	3.62	4.20	4.49
Customers Served	1,193,043	1,203,978	1,215,328	1,229,099	1,241,837

Minutes of Duration	2000	2001	2002	2003	2004
1	4,175,651	4,189,842	4,399,489	5,162,216	5,575,848
5	835,130	837,968	879,898	1,032,443	1,115,170
60	69,594	69,831	73,325	86,037	92,931
360	11,599	11,638	12,221	14,339	15,488
720	5,800	5,819	6,110	7,170	7,744
1,440	2,900	2,910	3,055	3,585	3,872
2,880	1,450	1,455	1,528	1,792	1,936

DTE-LDC 6-3

Request:

Regarding line loss, each electric company indicated that line loss was equal to the difference between energy requirement and energy sold, and that the loss includes various components such as actual system loss, theft, etc. Please list all the various components that your Company includes in reporting line loss, and briefly describe why each component is included in the line loss.

Response:

Distribution line loss is calculated as the difference between the energy received from generators and the sum of Company use and energy billed to customers. The components that make up the line loss, such as theft, losses on the system, and other unaccounted for energy, cannot be identified or measured separately. The Company does not calculate losses on individual components; rather, losses are determined on an aggregate basis as the difference between the total load reported to the ISO for settlement purposes for a given hour (energy received from generators) and the actual/estimated load at the retail meter for the same hour (the sum of Company use and energy billed to customers). A description of the load estimation process is provided in the attached "Supplier Load Estimation at National Grid (NE)".

Prepared by or under the supervision of: Michael J. Hager

Supplier Load Estimation at National Grid (NE)

Overview

The ISO-NE settles the hourly energy market (and other ancillary markets) in New England based on the participants' generation, tie lines and loads. The hourly generation and tie line quantities are directly measured and reported each day. However, supplier loads must be estimated because the cost of installing the required metering and communications equipment at customer locations would be prohibitively high.

The utility distribution companies in New England have implemented systems to estimate and report supplier loads in accordance with the ISO-NE requirements, as well as the regulations in each state. These systems rely on class average load profiles for customers without interval metering. National Grid developed a system called PULSE (Process Underlying Load Settlement) to develop and report the supplier loads in our service territory.

Supplier Load Estimation Requirements

Both the ISO-NE and the individual state regulatory commissions have addressed the process for estimating and reporting supplier loads. A key consideration is that the supplier loads must be estimated and reported daily, with only a 1-2 day lag.

Sources of Information

The PULSE system is closely integrated with several corporate data bases. Interface programs have been developed to provide the following information:

- Individual customer information for 1.7 million customers, including rate, supplier, load zone, monthly KWh usage, billing cycle, location, and account status. These data are updated daily from the Customer Information System (CIS).

- Historical hourly data for about 4,000 individual customers that have interval data meters, but are not read nightly.

- Hourly data for about 150 individual customers with modem-equipped interval meters.

- Class average load profiles, developed from statistical samples of customers in each state.

- Hourly data for generators, substations and tie lines (bulk data) needed to define the delivered load in each area.

- Total hourly load for each Node in the ISO-NE market model.

Daily Processing

The daily process for estimating supplier loads for a particular load date begins shortly after 12:01 am on the following morning when individual customer telemetered and delivered load area bulk data are collected. During business hours, these load data are validated and transferred to PULSE. Other incoming data from CIS are reviewed.

Once all data feeds are ready, the PULSE estimation programs are run. The programs perform the following functions:

- Aggregate the bulk load data to determine total hourly loads in each area.

- Compare the aggregated area hourly loads to historical hourly loads from last year and find the date with the most similar load shape (proxy date).

- Extract class average profiles for that date. These are used for residential and small commercial customers.

- Extract individual customer load shapes for that date. These are generally available for all commercial and industrial customers with demands exceeding 200 KW.

- For profiled customers, scale the class average load shapes according to the billed KWh for individual customers.

- Apply distribution loss factors[1] so that the preliminary estimates reflect the total amount of energy delivered from the transmission system each hour.

- Aggregate individual and scaled class average loads by supplier and area.

- Reconcile these preliminary hourly load estimates to the area hourly delivered loads by allocating the residuals to suppliers proportionately.

- Estimate transmission losses[2] from hourly generation and tie line data, and allocate to suppliers proportionately.

- Create output files containing the estimated hourly loads for each supplier.

Monthly Processing

Approximately 80 days after the end of a calendar month, the daily estimates are updated for more current information available from the billing system, as well as updated account information and actual (rather than historical) individual customer load data. Real time class average load shapes are also available and used at this time.

Reporting

The daily files and the monthly adjustments that are created by PULSE must be provided to both the ISO-NE and the individual suppliers. The daily load asset data (for both the energy and ICAP markets) are submitted to ISO-NE via their market interface system. The files containing individual suppliers' load data are e-mailed (automatically) to the appropriate email addresses.

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[1] Mass. Electric applies a factor of (i) 1.069 for all customers considered to be connected at secondary voltage levels (all customers except those in the G-3 rate class), (ii) 1.038 for all customers considered to be connected at primary voltage levels (all customers in the G-3 rate class with meters on the low side of the transformer), (iii) 1.027 for all G-3 customers with meters on the high side of the transformer, and (iv) 1.000 for all customers connected at transmission voltage.

These factors were established in 1996 based on the most recently available system loss study at that time.

[2] The estimate is based on the difference between the total zonal load determined at the PTF/non-PTF boundary point and the metered loads at the delivery points to Mass. Electric.

DTE-LDC 6-4

Request:

Regarding line loss, please describe:

(a) how the distribution and transmission loss factors that are reported to ISO-NE for the load settlement process are determined, include all supporting documents and a copy of the most recently reported loss factors for each voltage level;
(b) how often the distribution and transmission loss factors reported to ISO-NE are updated;
(c) what steps the Company currently takes to reduce its loss factors, and what steps the Company plans to take in the future to reduce its loss factors;
(d) how the Company benefits, if at all, from reducing its loss factors;
(e) what steps the Department could take to reduce loss factors;
(f) for what purposes, other than load settlement, the Company uses its loss factors, describe each purpose and provide any supporting documents.

Response:

(a) The Company does not report distribution and transmission loss factors to ISO-NE for the load settlement process; rather, the Company reports a supplier's total load obligation for settlement purposes, which represents the estimated/actual load at the customer meter adjusted for losses to the wholesale settlement point. A description of the load estimation process is provided in the attachment to DTE-LDC 6-3.

(b) The Company does not report, therefore it does not update, distribution and transmission loss factors.

(c) The Company does not utilize loss factors; however, the Company does take actions to reduce losses on its system.

The Company's losses are calculated as the difference between the energy received from generators and the sum of Company use and energy billed to customers. Thus, total losses include (i) transmission, transformation, and distribution losses, (ii) theft, and (iii) unaccounted for energy. While it is impractical to measure these components separately, nonetheless, the Company seeks to minimize (i) its transmission and distribution ("T&D") losses through the efficient design and operation of the distribution system, and (ii) the theft of its energy through the operation of its revenue protection department. The Company's total losses are heavily influenced by T&D losses, which are dependent on the customers' load factor on the distribution system.

DTE-LDC 6-4 (continued)

(d) The Company derives no benefit by reducing losses. Suppliers benefit through reduced load obligations for a given retail sale. To the extent suppliers pass along the benefits they derive, customers may gain benefits through lower commodity rates.

(e) Given the fact that the customers' load factor on the distribution system heavily influences the Company's total losses, there appears to be little that the Department can do to reduce the Company's losses, other than mandating the customers' acceptance of utility-administered direct peak load control.

(f) The Company does not use loss factors, other than as described in the load estimation process provided in response to DTE-LDC 6-3.

Prepared by or under the supervision of: Michael J. Hager